CA-IR-1

Ref: HECO T-1, Page 5, Lines 10 through 16.

Mr. Seu indicated the specific size limit to DG should "be construed relative to the utility's system loads and to the loads of large customers." For each of the islands served by the Companies, please provide the Companies' view or best estimate of the range of magnitude of the size limit to DG and the manner that the system load and the loads of each customer of each island were utilized to define such limit.

HECO Response:

The Companies have not formally defined size limits for DG on each of the islands. Notwithstanding this, it would be reasonable to consider both total system load and, for customer-sited DG, the load of the customer, the nature of the DG technology being applied, and the purpose of the DG application.

Regarding system load, it is useful to compare DG by service area with a total capacity of one-half to one percent of total system load, since few individual customers will have larger loads. For example, Oahu's recorded peak demand in 2003 was 1,242 MW-net[1], which would suggest an upper range of DG of 6 to 12 MW per site. It is possible that generating capacity of this size could be installed to serve the internal loads of some of HECO's largest customers. For Maui, the peak demand recorded in 2003 was 198 MW-net, suggesting an upper range of DG of 1 to 2 MW. The two 1 MW generators installed at Hana (as referred to in HECO T-1, page 6, lines 15-18) fit this range. For the Big Island, the peak demand recorded in 2003 was 186 MW-net, also suggesting a 1 to 2 MW per site upper range for DG.

For Molokai and Lanai, the peak demand recorded in 2003 was 6.6 MW-gross and 5.1 MW-gross, respectively. For these islands, applying the system load "rule-of-thumb" would

[1] With Chevron, Tesoro and Pearl Harbor generating an estimated 21 MW of power at the time. Had they not been generating power, the peak would have been 1,263 MW-net.

suggest an upper range of DG of 25 to 66 kW. However, in this instance, customer load and the nature of a DG technology should also be considered. For example, a hotel on one of these islands may well benefit from a CHP installation, provided the hotel's loads and thermal energy uses are large enough to allow installation of a cost-effective CHP system. As stated on page 22 of HECO T-1, CHP installations below about 200 to 250 kW may not be economical. Hence, for Molokai and Lanai, DG may well end up in the range of a few hundred kW.

The above discussion is general in nature and is not meant to serve as a rigorous basis for defining DG. As DG project opportunities occur, site-specific factors will always need to be considered which will influence the size of the installation.

CA-IR-2

Ref: HECO T-1, Page 5, Lines 19 through 21.

Mr. Seu indicated large scale cogeneration projects "require individual project or purchase power agreement applications with the PUC for review and approval."

a. In the Companies' view, will individual project or purchase power agreement applications also be required for DG projects whose output is exported to the electric grid?

b. If so, please describe the project or purchase power agreements for such DG projects as envisioned by the Companies at this time.

c. If not, please describe the manner the Companies envision such DG projects would be handled by the utility and the process for PUC review and approval, if any.

HECO Response:

a. Purchase power agreements, subject to Commission review and approval, will be required whenever a non-utility generator desires to be paid by the utility for power exported to the grid. Additionally, non-utility generators wanting to connect to the grid, but who do not seek to be paid for export power, even if there could be incidental amounts of power provided to the grid, are required to sign an interconnection agreement as provided in the Companies' respective Rule 14.H tariff.

b. At this time, the Companies have not envisioned any purchase power agreement review process for DG that is separate and distinct from its existing independent power producer review process.

c. Not applicable.

CA-IR-3

Ref: HECO T-1, Page 6, Lines 11 through 13.

Mr. Seu describes customer-sited emergency generation, which is used during power outages as an example of a DG application.

a. If the emergency generator is used only during periods of utility power outages, what, if any, impact does the emergency generation have on the utility or Hawaii's electric market? Explain.

b. How does the answer to part (a) above change if the emergency generator is utilized during periods when there is not a power outage; for example to manage the customer's use of electricity from the utility?

c. Do the Companies plan or operate their systems differently for customers that have customer-sited emergency generation for use during power outages than for customers without emergency generation?

d. Do the Companies plan and operate for the same level of service reliability for customers that do not have customer-sited emergency generation as for those that do have customer-sited emergency generation?

e. Is there a difference in the Companies' cost of serving customers that have customer-sited emergency generation versus those customers that do not have customer-sited emergency generation?

f. If customer-sited emergency generation is utilized during power outages only, what impact do the Companies believe the deployment of DG will have on future customer-sited emergency generation? Explain.

HECO Response:

a. Assuming the customer-sited emergency generator is sized to provide generation for the customer facility only, there will be no impact on the utility as the unit will not factor into generation planning or system operation. The use of an emergency generator at a customer site during a power outage will benefit that specific customer, but not the broader electric market.

b. If the emergency generator is used during periods when there is not a power outage, then for all intents and purposes it is no longer an emergency generator. It will have the same impacts to the utility and the broader electric market as any independent third party DG.

c. No.

d. Yes.

e. No.

f. The answer depends on the nature of the DG and the customer's requirements for emergency power. For example, if customer-sited DG is able to operate while connected to the utility as well as to operate isolated from the utility, then the DG may meet the power requirements of the customer during emergencies such that no separate customer-sited emergency generation is required. On the other hand, if the DG is not equipped to operate isolated from the grid, then it will not provide power to the customer during emergencies and the customer may choose to install emergency generation. Please see HECO-T-4, pages 2-3, for discussion of how DG may benefit the reliability of a single customer's electric service.

CA-IR-4

Ref: HECO T-1, Page 6, Lines 21 through 22.

Mr. Seu describes an example of a DG application as "a customer that is entirely self generating and not connected to the utility grid."

a. What impact does a self-generating customer, not connected to the grid, have on the utility or Hawaii's electric market?

b. How does the answer to part (a) above change for a customer that is entirely self generating and connected to the utility grid?

c. Do the Companies plan or operate their systems taking into account customers that are entirely self-generating and not connected to the utility grid? Explain.

d. If a customer's DG, which is entirely self-generating and not connected to the utility grid, is installed for use during power outages only, what impact do the Companies believe the deployment of DG will have on customers in the future that may be entirely self generating and not connected to the utility grid?

<u>HECO Response:</u>

a. If the self-generating power user was originally connected to the grid, then there will be a loss of revenues to the utility and the utility's remaining customers could be adversely impacted by the lack of contribution to fixed costs from the self-generating customer. If the self-generating power user was never connected to the grid, the utility loses potential sales.

b. If a customer is entirely self-generating and is connected to the utility grid, there may be adverse impacts to the utility and its other customers if the utility's rate schedules for the self-generating customer do not cover the costs of providing backup service to the customer.

c. No. Such customers have no direct impact on utility system planning or operations.

d. A self-generating, non-grid connected power user may choose to install separate emergency generation depending on the users particular reliability needs. To the extent that the power user remains off the grid, there will be no impact to this user if the utility or other parties deploy DG.

CA-IR-5

Ref: HECO T-1, Page 8, Lines 21 through 25.

Mr. Seu indicated that "customers making up this market will determine whether a form of DG is "feasible and viable for Hawaii".

a. What are the most important factors that the Companies believe will be taken into account by the customer to reach a decision to install customer-sited generation?

b. Explain why the factors identified in response to part (a) above are deemed to be the most important.

c. What effect, if any, do the Companies believe that the utility's rate structure and the charges for service provided by the Companies will factor in the customer's decision to install customer-sited generation?

d. To what extent do the Companies believe that the customers determination of forms of DG that are "feasible and viable" should match up with the Companies determination of feasible and viable forms of DG?

HECO Response:

a. All of the factors listed on HECO T-1, pages 7-8, are important, although individual customers may weigh factors differently. Customers generally will not consider technologies that are not technically feasible or commercially available or that are not able to address site-specific constraints (although this factor will vary among customers because it is site-specific). Some customers will be more concerned with life-cycle costs, while others will focus on upfront costs. (HECO T-1, page 8, lines 8-18.) Reliability is a more important customer need for some customers than for others, because of the differences in their business operations. A few customers may give more weight to externalities. (Response to CA-SOP-IR-2.) These are not the only factors that customers will take into account in deciding to install customer-sited generation. They will consider whether they are expanding or renovating their operations (HECO T-6, page 5.) They will consider the vendors and types of vendor offerings available to them. (HECO T-1, pages 24-26.)

b. See explanation provided in subpart a. When it comes to energy, the primary focus of commercial and industrial customers is on controlling costs. Hence, customer-sited generation has to provide sufficient economic value to the customer. Certain customers also require special electric service reliability, such as hospitals, and they may choose to install appropriately equipped on-site generation to meet those needs. Finally, all customers will require that customer-sited generation be compatible with their existing operations. For example, a resort hotel will consider noise and aesthetics in its decision to install a generating unit.

c. The utility's rate schedules and charges for service play directly into the customer's determination of the economic benefits of customer-sited generation. They serve as the baseline for comparison of customer-sited generation versus grid power.

d. The view of customers will drive the market. The Companies must determine what is cost-effective for the Companies to do as utilities, which must take into account market realities. The Companies must also consider the impacts and integration of third-party owned and customer-owned DG on and into utility systems based on what customers actually choose to do.

CA-IR-6

Ref: HECO T-1, Page 7, Lines 3 through Page 8, Line 8.

Mr. Seu identifies and defines seven criteria that must be met for a form of DG to be considered "feasible and viable for Hawaii."

a. Do the Companies believe that evolving technology will result in some prototype forms of DG that currently would not meet the Companies' criteria could or may be expected to meet such criteria in the Companies IRP planning horizon?

b. How do the Companies propose to evaluate and consider forms of DG that at the moment do not meet the criteria in the present, but could or may be expected to meet the Companies' criteria in its IRP planning time frame?

HECO Response:

a. The Companies believe that technology will evolve, and it is entirely possible new forms of DG will arise over the next decades that do not currently fit the criteria.

b. The Companies regularly monitor new technologies and trends in the power industry, and support research or demonstration projects to evaluate the feasibility of such new technologies. The Companies perform these activities both through their membership in industry organizations such as the Electric Power Research Institute ("EPRI") and directly in utility projects. As an example, HECO recently conducted a microturbine demonstration project at its Ward Avenue facility to evaluate the feasibility of the technology when firing diesel. As a second example, the HECO Ward Avenue facility is currently serving as a host site to the Hawaii Natural Energy Institute's Hawaii Fuel Cell Test Facility.

CA-IR-7

Ref: HECO T-1, Page 12, Lines 5 through Page 13, Line 3.

Mr. Seu identifies the ownership and operation and maintenance options for each of the seven forms of DG applications identified by the Companies.

a. For each of the DG applications, indicate whether the DG facilities in that application could be interconnected with the utility for customer-sited DG or interconnected with the customer for substation-sited DG.

b. For each of the DG applications, describe the expected metering arrangements, including whether the DG would be metered for customer-sited DG and whether net metering would be applicable for customer-sited DG.

c. For the customer-sited DG applications, describe whether the entire output of the DG facility could be separately metered and utilized.

d. The substation sited-generation DG applications 2 and 3, as indicated by the Companies would be owned by the utilities.

    1. Would the Companies consider substation-sited generation owned by other parties? Explain why or why not.

    2. Do the Company believe that legal or regulatory constraints prevent such non-utility ownership? Explain.

<u>HECO Response:</u>

a. Please see the table below.

b. Please see the table below.

c. Please see the table below.

DG Application	Interconnect with Utility Possible?	Interconnect with Customer Possible?	Revenue Metered?	Net Metering Possible?	Entire DG Output Metered and Utilized?
Customer-sited emergency generation	no		no	no (assuming energy consumed by customer only)	no
Substation-sited peaking generation		no			
Substation-sited generation for T&D purpose		no			
Customer-sited CHP	yes		yes, if utility-owned or if PPA in effect	yes, subject to HRS §269-101	yes
Customer-sited cogeneration	yes		yes, if utility-owned or if PPA in effect	yes, subject to HRS §269-101	yes
Off-grid, customer-sited generation	no		no	no	no
Customer-sited generation operated in parallel w/grid	yes		yes, if utility-owned or if PPA in effect	yes, subject to HRS §269-101	yes

d. No. The Companies would not consider substation-sited generation owned by other parties due to legal and/or regulatory constraints, and other practical factors such as maintaining safety, and security over the transmission and distribution system. Substation sites are rate-based utility assets and the utility would not be in a position to make the sites available for third-party use, without PUC approval.

CA-IR-8

Ref: HECO T-1, Page 13, Lines 6 through Page 14, Line 14.

Mr. Seu describes the Companies' plans to pursue each of the seven DG applications.

a. Under what circumstances, if any, would the Companies consider providing customer-sited emergency generation?

b. Under what circumstances, if any, would the Companies consider substation-sited generation owned by parties other than the utilities?

c. With respect to customer-sited CHP systems offered by the utilities, under what, if any, circumstances do the Companies believe that the CHP service does not unduly burden other customers?

d. Under what circumstances if any would the Companies consider offering off grid, customer-sited generation?

HECO Response:

a. The Companies' have not identified such circumstances. The Companies' reasons for not providing such generation at this time were provided in response to CA-SOP-IR-12.

b. None. See also HECO response to CA-IR-7, part d.

c. As stated on page 17 of HECO T-1, the Companies' have identified the factors to be considered. The Companies' performed an extensive economic analysis in Docket No. 03-0366 that considered all the numerous revenue and cost impacts of a utility CHP program. The analysis showed a positive net present value benefit for all of the Companies, indicating the utility CHP Program is cost-effective from a Utility Cost Test perspective. On this basis, the Companies' ratepayers as a whole are better off with utility CHP participation than when the CHP is provided only by non-utility developers. From this perspective, the utility CHP service does not unduly burden non-participating customers.

d. The Companies' have not identified such circumstances.

CA-IR-9

Ref: HECO T-1, Page 14, Lines 17 through 25.

Mr. Seu describes the potential benefits of DG with respect to the deferral of new utility facilities.

a. Do these potential benefits of DG also apply to DG applications of customer-sited emergency generation and off-grid, customer-sited generation?

b. How do the Companies take into account the benefits of customer-sited emergency generation or off-grid, customer-sited generation applications? Explain.

HECO Response:

a. No.

b. The Companies do not assign any planning or operating benefit to customer-sited emergency generation or off-grid, customer-sited generation.

CA-IR-10

Ref: HECO T-1, Page 15, Lines 8 through 13.

Mr. Seu indicates that the utility and its ratepayers benefit by the customer choosing utility-owned CHP over self-owned or a third party owned CHP system.

a. Does this statement mean that utility-owned CHP systems should be chosen over CHP systems owned by the customer or a third party? Explain.

b. What are the considerations or circumstances under which the Companies believe the utility and its ratepayers benefit if CHP is not the utility but is owned by a customer or a third party?

HECO Response:

a. From the standpoint of the utility and its ratepayers, utility-owned CHP is generally preferable compared to customer-owned or third party-owned CHP. Utility ownership of CHP provides for a bigger CHP market and greater system benefits in terms of improving system efficiency and reliability, deferring or avoiding T&D and generating capacity, and deferring or avoiding fuel and variable O&M costs. Utility ownership of CHP also is preferable from a rate impact standpoint. From the standpoint of the CHP host customer, there are a number of potential benefits provided by the utility-owned CHP option, including the customer not needing to handle O&M of the CHP and the fact that the project would be done by a regulated entity. The qualitative and quantitative benefits that are provided by utility-owned CHP to the utility, its ratepayers, and host CHP customers were discussed in HECO T-1, pages 15-21, and HECO T-3, pages 7-12.

In summary, from the utility and ratepayer standpoint, utility-owned CHP is preferable. From the CHP host's standpoint, there are a number of factors which can make the utility option preferable to self-generation or contracting with a third party, but ultimately, a CHP host will choose its CHP provider on the basis of specific economic, reliability, and compatibility factors as were described in response to CA-IR-5.

b. Each potential CHP installation is subject to site-specific factors that may impact the feasibility of the project. For example, a site may be challenged by fuel delivery or environmental permitting constraints that would significantly add to the cost of the project. If the costs of the project are so high that they outweigh the economic benefits of retaining the customer revenues or providing capacity, then it could be argued that the utility and its ratepayers are better off if a third party does the CHP system project (or, possibly, the customer not do the project at all).

CA-IR-11

Ref: HECO T-1, Page 17, Line 18 through Page 18, Line 6.

Mr. Seu describes the loss of revenue potential due to third-party owned CHP. Do the Companies have any other options to address the revenue loss concern resulting from the implementation of third-party CHP other than by discounting the current rate structure to avoid the net revenue reduction impact to MECO's remaining customers on Lanai?

HECO Response:

MECO, in its application to the Commission in Docket No. 03-0261, proposed the discount while also contemplating the installation of a utility-owned CHP system at a time closer to the need date for additional generation on the island of Lanai. The third party proposal was for a combination of CHP and customer-sited electrical generation, at a magnitude such that the customer would have completely bypassed the MECO system on the island and caused MECO to lose 40% of its Lanai sales. Thus, MECO's options to respond to the situation were to offer the discount, and help facilitate the installation of a number of energy conservation measures, to defer the customer's CHP project, and to encourage the customer to plan a CHP project (whether utility, third-party, or customer owned) that would be better sized and timed to fit with the island's overall generation needs.

CA-IR-12

Ref: HECO T-1, Page 19, Lines 4 through 8.

a. Please identify and provide the analysis referenced that considered the revenues for supplemental and backup services under regular rate schedules.

b. Also please identify the regular rate schedules referenced in the testimony.

HECO Response:

a. The analysis is that which was performed and submitted by the Companies in its CHP Program Application, Docket No. 03-0366.

b. The backup service rate schedule referred to is HELCO's Rider A – Standby Service.

CA-IR-13

Ref: HECO T-1, Page 19, Lines 24 through 25.

a. Mr. Seu indicates "the ability of the utility to directly control the operations and maintenance of a CHP system will improve its impacts on system reliability and power quality." Could the same impacts and benefits be derived from customer or third-party owned CHP systems if the utility has direct control over the operations and maintenance of the CHP system? Explain.

b. Please provide examples of how the operation and maintenance of a CHP facility not under the direct control of the utility would differ from that which is under the direct control of the utility.

c. Please identify the potential conflicts of interest of a customer or third-party owned CHP system under the direct control of the utility.

HECO Response:

a. If the system is designed and installed in a manner consistent with utility standards, then in general, the same impacts and benefits could be derived if the utility is directly in control of the operations and maintenance of the system. If the system is not consistent with utility standards, for example, sub-standard components are used causing more frequent breakdowns, there may still be adverse impacts on system reliability and power quality even if the utility is given control over operations and maintenance.

b. A third-party CHP system would be operated to maximize benefits to the customer and the CHP system owner. The utility-owned CHP system would be operated and maintained to balance the customer benefits with the overall utility operation with specific examples below:

Having real-time dispatchability of the CHP units as described below differentiates the utility-owned and operated CHP systems:

- Voltage support: the utility CHP system would standardize the use of synchronous generators. This would allow limited customer and regional voltage support benefits.

- Control logic dispatch: the Companies are still finalizing their preferred CHP unit dispatch parameters, but is considering control system modifications to allow (4) control modes for utility CHP systems which are not currently used on any of the third party installed CHP systems in Hawaii:
  - Normal: the CHP power output would be balanced with the customer's thermal load to minimize the dumping of excess waste heat.
  - Peaking: on command, the CHP unit would maximize its power output without backfeed to the grid. This would provide system generation capacity support and/or support regional distribution system load in the event of a secondary feeder outage or temporary high loads.
  - Minimum: on command, the CHP unit would minimize its power output. This mode is targeted to the neighbor island systems where on-line regulating units may already be at minimum load and backing off the CHP units would allow greater operating margin on the regulating units.
  - Shutdown: utility system operators would be able to remotely shut-down each CHP system due to local network problems and lineman safety.

The maintenance of utility-owned and operated CHP systems would allow the scheduling of maintenance outages to minimize conflicts with distribution system maintenance work and other utility system considerations where regional distributed generation would support the local power quality and reliability.

c. If the customer or third party-owned CHP system is under the direct control of the utility, the customer or third party may question how the utility is dispatching or maintaining the CHP system. For example, the utility may decide, based on experience with similar units at other sites, that it needs to bring a customer-owned CHP system down for emergency maintenance. The customer may or may not agree with this determination, as they may be more concerned that the CHP system is not operating and is therefore not providing the CHP energy efficiencies to its facility. As another example, the customer or third party may decide to select a brand of CHP system equipment based primarily on near-term capital costs, whereas the utility would be more concerned about life-cycle costs including O&M and would have preferred to operate and maintain another brand of CHP equipment which is standardized with the utility's broader equipment inventory.

CA-IR-14

Ref: HECO T-1, Page 25, Lines 9 through 11.

The referenced testimony Indicates that customer support for utility owned CHP was the sentiment that the utilities' involvement provides more choices and options among CHP vendors, which maximizes competition in the market. The testimony at pages 15 through 21 indicates, however, that CHP systems that are not owned by the utility are not as favorable or beneficial as utility owned CHP.

a. Should utility-owned CHP systems be favored over non utility owned CHP systems? Explain.

b. What advantages or benefits would non-utility owned CHP systems have over utility-owned CHP systems? Explain.

c. Is there a maximization of competition in the market if the Companies believe that only utility-owned CHP systems make sense for the utility and its ratepayers and thus have the opportunity to discount a customer's rates to retain the customer's load when the customer is considering installing a non-utility owned CHP system? Explain.

<u>HECO Response:</u>

a. The Companies believe that from the broad utility and ratepayer standpoint, utility-owned CHP systems are preferable over non-utility CHP systems. From a CHP host's standpoint, there may be features of the utility's proposed CHP program that are preferable, however, each host customer will ultimately choose its CHP provider on the basis of the specific economics, reliability, and compatibility factors of the various proposals it receives. See also the responses to CA-IR-10, subpart a., and CA-IR-5.

b. Non-utility CHP systems may offer quicker installation schedules compared to utility systems, to the degree that the utility needs to obtain PUC approval for projects done under Rule 4. The non-utility provider may also have more flexibility in providing additional services and equipment that would otherwise be considered below the line from the utility's standpoint. In any case, a customer considering utility versus non-utility CHP proposals will weigh site-specific factors in deciding which system to choose. See also response to subpart a. above.

c. Providing customers with as many choices for CHP as possible maximizes competition. Allowing the utility to directly participate in the CHP market provides an alternative CHP model that customers may find attractive, depending on their particular priorities or objectives. The utility perspective is that utility-owned CHP provides the most benefits to the broader base of ratepayers, however, individual CHP customers are free to decide whether or not to develop CHP with a non-utility provider.

CA-IR-15

Ref: HECO T-1, Page 29, Lines 9 through 15.

The testimony indicates that concerns have been expressed by others regarding an unfair advantage by the Companies versus the standby charges in HELCO's Rider A standby service.

a. Do the Companies see the administration of rates and standby charges differing between utility-owned CHP systems and non-utility owned CHP systems, creating at least the appearance that utility-owned CHP is being handled differently and having an advantage over non-utility owned CHP systems? Explain.

b. Would an alternative to addressing this perception be that any CHP system, whether owned by the utility, the customer or third party, be assessed the same rates and charges for standby service and be related directly to whether the DG is directly controlled by the utility in use of its output?

HECO Response:

a. Although HELCO's position, as described in HECO T-1, pages 29-30, is that the Commission should rule on the fairness of applying the standby service rider in light of the utility's CHP offering, Informal Complaint No. IC-03-098 does show that there is an appearance to some parties that utility-owned CHP is being handled differently from non-utility owned CHP in the administration of standby charges, thereby providing an advantage to the utility systems.

b. It is not clear what "and be related directly to whether the DG is directly controlled by the utility in use of its output" is intended to mean in the context of this question. The "alternative" would not address the perception. The Company would have to charge different rates than those based on its rate schedules for CHP system electricity (i.e., for CHP service), charge for "supplemental" service (i.e., electricity from the grid) based on its rate schedules, and for backup service based on Rider A. If the Company's CHP system performed well, it would receive more revenues for CHP service and less for back-up service. If the CHP system performed poorly, the Company would receive less revenues for CHP service and more for back-up service. The customer would be indifferent (as long as the CHP system thermal output was sufficient for its needs) since the utility would provide both services. Rider A makes sense where the providers of CHP service, and backup and supplemental service, are different entities.

CA-IR-16

Ref: HECO T-1, Page 30, Lines 6 through 9.

Please expand on the "sole supplier" provision that the Companies have reconsidered and will delete from its standard cogeneration energy purchase agreement. Explain the basis for the Companies' position on this matter.

HECO Response:

The Companies' CHP Program application in Docket No. 03-0366 proposed that the Companies would have the right to terminate a CHP Agreement if the CHP customer uses electricity not supplied by the Companies, other than energy from a non-fossil source or from the customer's own emergency generator when operated during emergencies, for limited test periods, or at the Companies' request. The Companies reconsidered this provision to enable customers to have more freedom of choice in how they want to meet their energy needs.

CA-IR-17

Ref: HECO T-1, Page 32, Lines 6 through 11.

The testimony indicates that larger units for CHP projects are likely to be required than are covered by the HECO-HESS teaming agreement. Please elaborate on these larger units and whether such larger units are considered by the Companies to be DG.

HECO Response:

HECO has been made aware of several potential CHP projects on Oahu that would be larger than what is covered in the HECO-Hess teaming agreement. These projects would be for customers with larger loads and the total CHP capacity could be as high as 5 to 10 megawatts at a site. HECO would still consider such installations as DG given their relatively small size compared to overall system load.

CA-IR-18

Ref: HECO T-1, Page 37, Lines 8 through 14.

The testimony describes the Companies' view that if CHP and DG are to play a larger broader role, the utility should be directly involved in developing and owning CHP and DG projects.

a. Do the Companies believe that third-party or customer owned CHP and DG projects could provide the same benefits as utility-owned DG? Explain.

b. Under what circumstances, if any, could non-utility owned CHP and DG systems provide the same benefits as utility owned CHP and DG systems?

HECO Response:

a. Third party or customer owned CHP and DG could provide some of the same generic benefits as utility-owned units only to the extent that they meet utility standards for design, operability (including dispatchability), and reliability. These generic benefits may include deferral of new central station generating capacity, displacement of utility central station generation fuel and variable O&M costs, deferral of new T&D capacity, and improved T&D system reliability and power quality. However, only utility owned CHP or DG provides the benefit to ratepayers of retaining customer load and avoiding uneconomic bypass. Additionally, the overall CHP market will be larger only if the utility is able to offer its utility-owned and operated CHP services to customers. See HECO T-3, page 7-10, and HECO T-4, pages 15-16. Please also refer to HECO's response to CA-IR-10, subpart a., CA-IR-13, subparts a. and b., and CA-IR-25, subpart a.

b. As stated above, some of the same generic benefits may be achieved only if the non-utility CHP or DG meets utility standards for design, operability (including dispatchability), and reliability. In no cases, however, will non-utility CHP or DG provide the benefits of avoiding uneconomic bypass or increasing the size of the CHP market. Thus, non-utility CHP or DG cannot provide all of the same benefits as utility-owned CHP or DG.

CA-IR-19

Ref: HECO T-2, Page 14, Lines 3 through 9.

Mr. Seki indicated that "grid interconnection of wind turbines may be challenging" and that the "[f]luctuating output from wind turbines can negatively impact voltage and frequency of the electric utility system."

a. Please expand on the statements by providing specifics information regarding the interconnection and operations of wind turbines and their impact on the electric utility system.

b. Please provide examples and descriptions of the Companies' experiences relating to the interconnection and operation of wind turbines.

HECO Response:

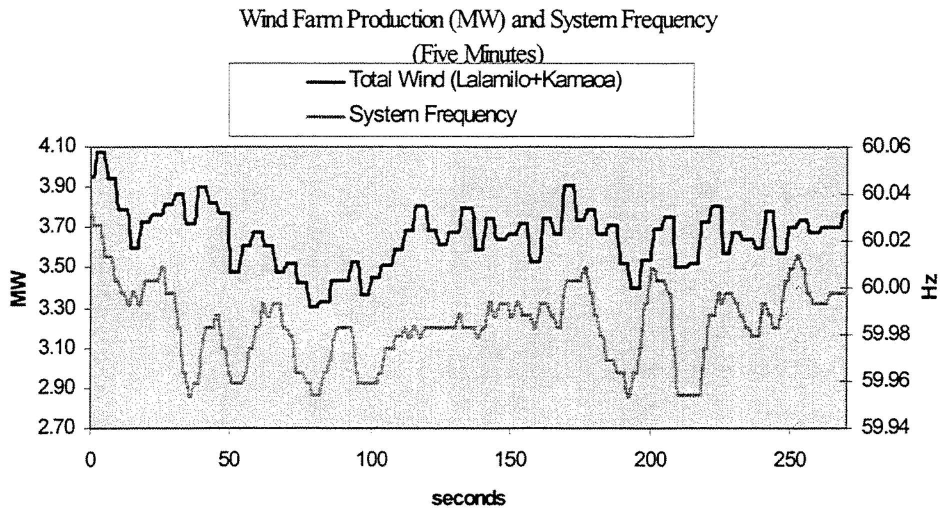
a. Page 4 of this IR response is an example of an actual plot of data taken from HELCO's Energy Management System. The top line shows the combined output from Lalamilo and Kamaoa Wind Farms, which are the two operating wind farms on the Big Island. The bottom line is a plot of the system frequency with the same time stamp as the Lalamilo/Kamaoa data. The plot demonstrates empirical evidence of a strong correlation between the effect on system frequency based on the fluctuations from the wind farms. This information was presented at the May 2004 Utility Wind Interest Group (UWIG)/American Wind Energy Association (AWEA) joint wind conference as part of a technical presentation on wind farm impacts on utility system operations. The entire slide presentation is attached to this IR response. In order to protect the stability of the HELCO system, performance standards for ramp rates and power fluctuation rates have been developed for HELCO. A detailed discussion on performance standards for the overall electric utility industry perspective was discussed in Docket No. 00-0135 (Apollo Complaint Docket). HELCO is currently in negotiations with Apollo Energy Corporation to repower its existing 9.25 MW

Kamaoa Wind Farm to a 20 MW wind farm located in South Point. In Decision and Order No. 18568, filed May 30, 2001, the PUC stated "The commission believes that the inclusion of performance standards in the PPA are reasonable to mitigate the impacts of Apollo's wind turbine generators on HELCO's power quality and system reliability." Since the filing of Decision and Order No. 18568, HELCO and Apollo have agreed upon ramp rates and power fluctuation standards for the Apollo 20 MW wind farm. Performance standards similar to Apollo's were included in the Power Purchase Agreement ("PPA") for Hawi Renewable Development ("HRD") Hawi-2 10.56 MW wind farm project at Hawi on the Big Island. The PPA was approved by the PUC on May 14, 2004, Decision and Order No. 20979. The performance standards included in the HRD Hawi-2 PPA are as follows:

Ramp Rate	
Sustained:	2 megawatts/minute ramp up, and 2 megawatts/minute ramp down when operationally possible
Power Fluctuation Rate	
Instantaneous:	1 megawatt/2-second scan
Subminute Average:	an average of 0.3 megawatt/2-second scan for any 60-second period

Wind farms can also affect other areas of system operations. Included on pages 10-13 of this IR response is information regarding underfrequency and undervoltage ride through concerns with the operation of wind farms. In summary, disturbances such as a generator unit trip, which can occur under normal system operation, will cause the system frequency to decay. Automatic underfrequency load shedding schemes are designed to shed a pre-determined amount of load which will 1) arrest the system frequency and prevent it from further decay, and 2) restore the system frequency to 60 Hz. If the wind farm does not coordinate its underfrequency ride through capabilities with the utilities' protection schemes, the wind farm could trip off line while the automatic schemes are being implemented to restore the frequency and the system could become unstable which could lead to an island-wide black out situation.

Under voltage ride through is another issue with wind farms. A fault on the system will cause low voltages on the utility system. Without a coordinated undervoltage ride through, a wind farm could trip off-line because of the low voltages caused by the system fault. If the wind farm is generating at a MW level where loss of the wind farm would cause the frequency to decay and trigger the underfrequency load shedding scheme, customers would be shed each time a fault occurs on the system and the wind farm output is high. Many fault occurrences on a transmission and distribution line cannot be controlled by the utility because faults can occur with a lightning strike, with high winds, with automobile accidents in which there is damage to the utility's equipment poles or structures, etc.



b. Please see response to subpart a. The Company has also conducted interconnection studies for several wind farms for HELCO and MECO. See, for example, the executive summary for Interconnection Requirements Study for Hawi Renewable Development's Proposed 10.56 MW Wind Farm (HRD Hawi-2) Connected to the HELCO Transmission System at Hawi, which was included as Exhibit 8 to the application filed on January 20, 2004, Docket No. 04-0016. The Commission approved the power purchase agreement between HELCO and HRD Hawi-2 on May 14, 2004 in Decision and Order No. 20979, Docket No. 04-0016.

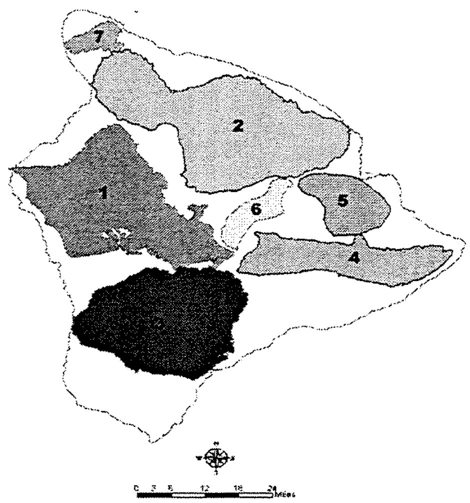
HELCO Utility Operation with Wind Farms

UWIG System Operations Session
Albuquerque, New Mexico
May 17, 2004

Presentation Overview

- Background on the HELCO System
- Challenges and Issues with Wind Energy on the HELCO System
- Underfrequency Ride-Through Requirements
- Undervoltage Ride-Through Requirements

Comparative Size of the Hawaiian Islands and Customer Density



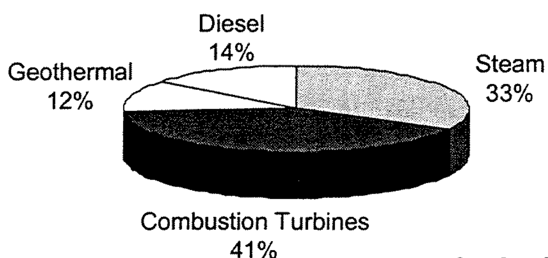
Customer Density

HECO	474/sq.mi.
Maui	53/sq.mi.
HELCO	17/sq.mi.
SCE	84/sq.mi.
PG&E	68/sq.mi.

1 Island of Oahu
2 Island of Maui
3 Island of Kauai
4 Island of Molokai
5 Island of Lanai
6 Island of Niihau
7 Island of Kahoolawe

HELCO System Capacity

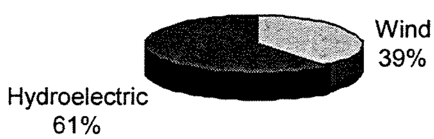
Firm Capacity (253 MW)



System Peak (MW)

HECO	1,242 [1]
Maui	198 [1]
HELCO	188 [1]
SCE	20,477 [2]
PG&E	24,681 [2]
PNM	1,661 [3]

As-Available Energy (25 MW)



Note 1: Based on 2003 peaks (net)
Note 2: Forecasted 2004 load from the 2002 California ISO Controlled Grid Study Report
Note 3: From the 2003 PNM Annual Report

HAWAII ISLAND
Wind Resource

Existing Wind Generation
Lalamilo 2.3 MW

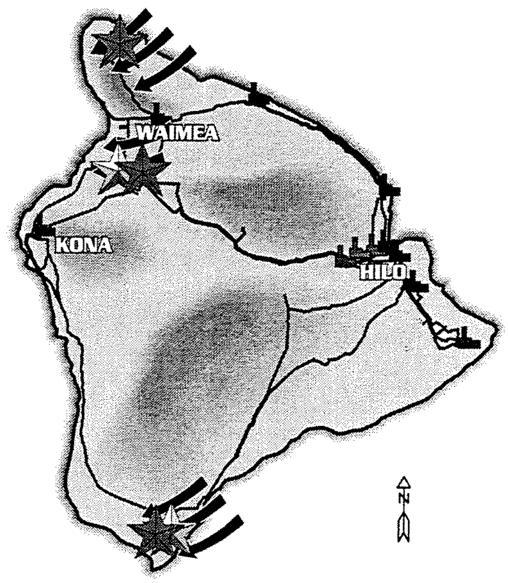
•Kamaoa 7.0 MW

Future Wind Generation

•Hawi 10 MW

•Lalamilo 10 MW

•Kamaoa 20 MW



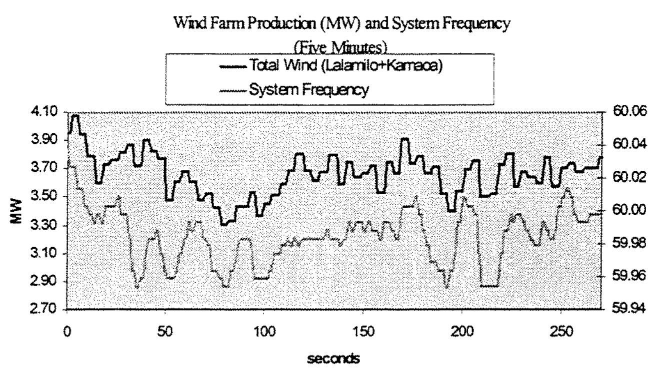
Hawaiian Electric Company, Inc.
Planning & Engineering Department

Current Challenges with Wind Energy on the HELCO System

- Resources are located far from major load centers
- Wind generation requires additional operating reserve to be on-line
- Wind generation does not displace firm capacity and requires the availability of back-up generation
- 1980's vintage WTGs on the system
- Problems with system frequency regulation and power quality
- Limited demand in Hawaii coupled with no interconnections leads to curtailment of wind generators
- Costs

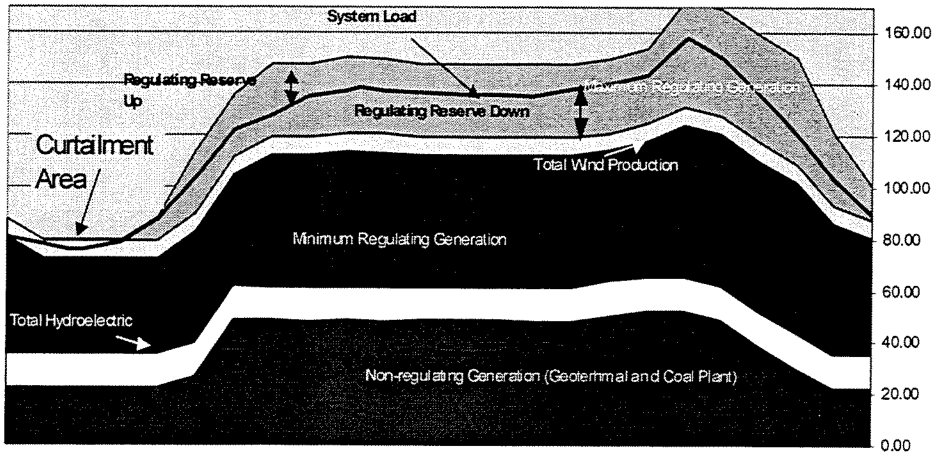
Issues with Increased Penetration of Wind Energy on the HELCO System

- As-available and intermittent resource
- Regulating units would be worked even harder to maintain system stability
- Further curtailment of wind generation
- Need additional operating reserve
- Need supplemental technologies to ride through faults and frequency excursions
- Energy storage could "firm up" wind generation but is costly



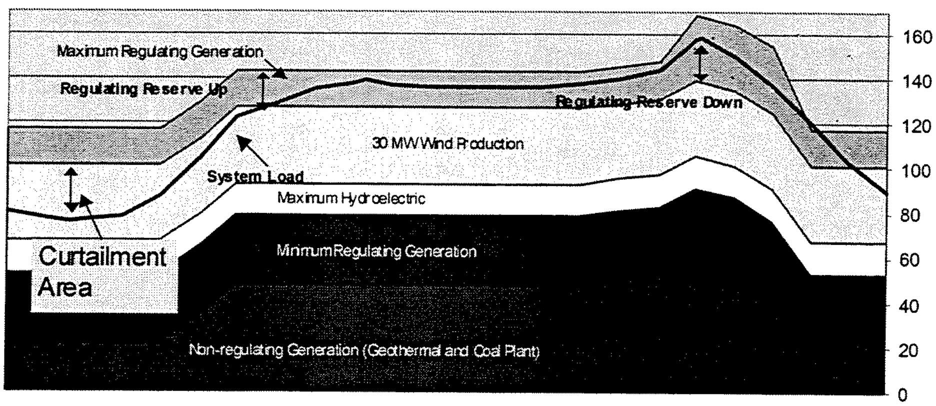
Current HELCO Load Curve

Curtailment Issues



Future HELCO Load Curve

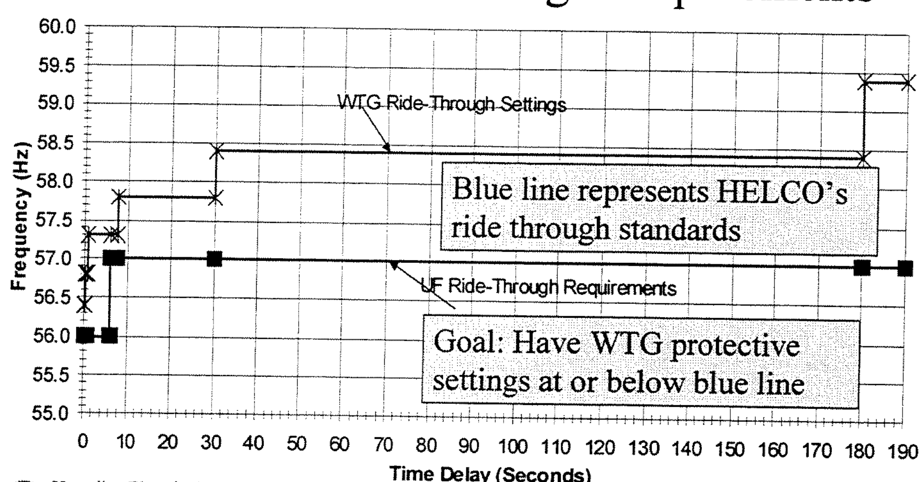
Generation Characteristics for Future Wind Production (Assumes Three Steam Units can Maintain Frequency)



Underfrequency Ride-Through

- HELCO employs an underfrequency load shed scheme to restore frequency stability.
  - Last block of the existing scheme is set to operate at 57 Hz
  - The HELCO underfrequency load shed scheme provides the turbine underfrequency protection for the HELCO generators
- Plan for worst-case generation loss contingencies, (e.g. loss of a large generator on the HELCO system), which can result in frequency dropping below 57 Hz for a few seconds

Proposed WTG UF Ride-Through Versus HELCO UF Ride-Through Requirements



Undervoltage Ride-Through

- Undervoltage Conditions Due to Faults
  - System short circuits
  - System voltage levels can be extremely low

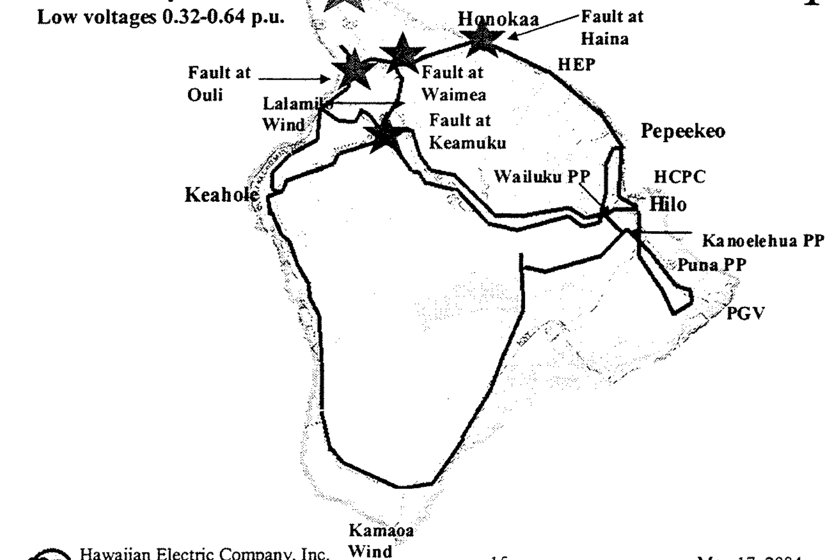
HRD WTG Terminal Voltages (pu) For 69 kV Transmission Faults
Near The Ouli, Keamuku, Waimea, and Haina Switching Stations

Fault Location	Single Line-To-Ground	Line-To-Line	3-Phase
Ouli	0.64	0.61	0.49
Keamuku	0.61	0.62	0.48
Waimea	0.42	0.45	0.32
Haina	0.53	0.54	0.46

Underfrequency Ride-Through (cont)

- Loss of the Wind Farm will worsen the underfrequency problem
- HELCO will have to shed extra customers to compensate for the loss of the Wind Farm if the UF protection settings do not coordinate with the utility

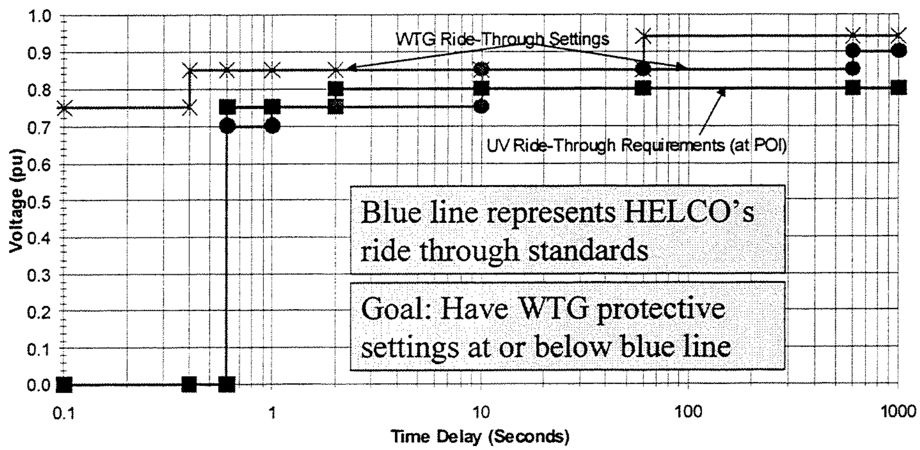
HRD Fault Example



Undervoltage Ride-Through (cont)

- Time frame based on the speed of the protective relaying (From initiation of fault to fault clearing and voltage recovery):
  - 200 msec. for the primary protective relays
  - 350 msec. for breaker failure
  - Up to 700 msec. for the back-up relays to clear multi-phase faults
  - Up to 2 seconds for the back-up relays to clear single line-to-ground (SLG) faults
    - More than half of the faults on the HELCO system are SLG faults
    - There have been events where back-up relaying was required to clear SLG faults

Proposed WTG UV Ride-Through Versus HELCO UV Ride-Through Requirements



Undervoltage Ride-Through (cont)

- Loss of the wind farm due to an undervoltage event could trigger an underfrequency event
- HELCO would have to shed customers to compensate for the loss of wind farm if the UV protection settings do not provide adequate undervoltage ride through

Status Report

- Through HELCO's involvement with the WTG manufacturers:
  - WTG manufacturers have agreed to HELCO's UF ride-through settings
  - WTG manufacturers are close to meeting HELCO's UV ride-through settings
  - External VAR systems (proposed by the Wind Farm Developer) to improve wind farm UV ride-through capabilities are also being evaluated

Thank you.

CA-IR-20

Ref: HECO T-2, Page 15, Lines 1 through 11.

a. In addition to defining "small" relative to utility system loads and to the loads of large customers, do the Companies consider the location of wind turbines on the Companies' distribution system to be a factor in evaluating whether the definition of capacity rating for the lower and upper limits for the wind turbine falls into the "small" DG category? Explain.

b. Is the same location consideration relevant to other forms of DG in addition to wind turbines? Explain.

HECO Response:

a. The Companies may consider the location of wind turbines on the Companies' distribution system to be a factor in considering whether a wind turbine is deemed "small", to the extent that the Companies' distribution system includes 25kV, 12kV, and 4kV voltage levels. In addition, the location of the wind turbine on a distribution feeder is a factor in determining the system impact, such as voltage regulation and fault current contribution.

b. Yes, the same location consideration is relevant to other forms of DG.

CA-IR-21

Ref: HECO T-2, Page 18, Lines 8 through 11.

Mr. Seki indicates that some equipment upgrades may be required to accommodate small DG wind systems.

a. Please expand on the specific equipment upgrades that may be required and explain the circumstances under which the upgrades would be required.

b. Please provide examples of the Companies' experiences of the circumstances requiring such equipment upgrades and the equipment upgrades that were installed to accommodate DG on the Companies' electric systems.

HECO Response:

a. Equipment upgrades include (but are not limited to) feeder reconductor and/or reconfiguration, breaker replacement, relay upgrades, and direct transfer trip equipment. Upgrades would be required to resolve potential adverse system impacts such as voltage regulation problems, overvoltage, unintended islanding, relay miscoordination, excessive fault current contribution, etc.

b. In 2003, The Fairmont Orchid on the Big Island installed 4-200kW synchronous generators. To avoid overvoltage problems due to the new generators under certain system conditions, HELCO required the implementation of direct transfer trip equipment.

CA-IR-22

Ref: HECO T-2, Page 26, Lines 4 through 6.

Mr. Seki indicates that PV may be feasible for off grid applications.

a. Are renewable small generators that are utilized for off-grid applications included in the RPS definition and the computation of attaining RPS goals?

b. Is the RPS level reported by HECO, HELCO and MECO inclusive of off-grid renewable resources?

HECO Response:

a. Renewable small generators that are used for off-grid applications do not appear to be included in the RPS definition. The RPS Status Report filed by the HECO Utilities on February 27, 2004 does not include off-grid renewable resources in the calculation of the RPS percentage.

b. See response to part a. above.

CA-IR-23

Ref: HECO T-3, Page 2, Lines 16 through 23.

The testimony indicates that firm capacity is the generating capacity, which can be called upon by the utility to safely and reliably provide energy in defined amounts at scheduled times. The testimony goes on to state that "in many instances, DG can be considered firm capacity. In order for a DG installation to be considered firm capacity, the utility should be able to control the operations of and maintenance quality of the installation. The DG should also have a reliable fuel supply and an adequate amount of fuel storage." What DG technologies would meet the firm capacity requirements described above? Explain.

HECO Response:

Among the DG technologies that are feasible and viable for Hawaii, internal combustion engines and combustion turbines would meet the criteria to be considered firm capacity. Other DG technologies, such as microturbines and fuel cells, which could possibly meet the criteria to be considered firm capacity, are not considered feasible and viable for Hawaii at this time. Mr. Scott Seu, in HECO T-1, pages 7 to 9, describes the criteria that would determine whether a DG technology is "feasible and viable for Hawaii". As stated on HECO T-1, page 9, lines 13 and 14, "Microturbines and fuel cells are still in the formative stages of the product development cycle and their use is very limited." Mr. Art Seki, in HECO T-2, page 9, line 15, also states that "Fuel cell equipment is still expensive and not commercially available."

Renewable DG technologies, such as wind, run-of-river hydro and photovoltaics ("PV") are considered "as-available" and would not be considered firm capacity. On the other hand, PV coupled with energy storage systems, typically used for off-grid applications, are commercially available. PV with energy storage could possibly be used for grid-connected systems and be considered firm capacity, depending on the utility's ability to control the operations of and maintenance quality of the installation. Mr. Seki provides extensive discussion of PV with storage in HECO T-2, page 4, line 23 to page 5, line 2, and page 6, line 6 to page 8, line 9. Wind and run-of-the-river hydro DG with energy systems, which are not as common as PV with energy storage systems, could also possibly be used for grid-connected systems and be considered firm capacity.

CA-IR-24

Ref: HECO T-3, Page 3, Lines 4 through 6.

The testimony indicates that "[y]es, if the DG can be considered firm capacity and the DG facility (or multiple DG facilities in aggregate) are sufficiently large, it can defer the need for new central station generating capacity." What capacity amounts in kilowatts (kW) would be considered "sufficiently large?" Explain.

HECO Response:

"Sufficiently large" in the context of whether or not DG can defer the need for new central station generating capacity cannot be defined by a specific kW value. The amount of firm capacity DG needed to defer the need for new central station generating capacity will depend on a number of factors, including but not limited to, the magnitude of the utility's system loads, the amount of the capacity planning criteria violation in the year new central station capacity must be added, the coincidence of the DGs operating hours relative to the utility's system peak hours, and the DG's maintenance schedule. A particular size of DG (or multiple DGs in the aggregate, for example 5 MW) may be sufficiently large to defer new central station capacity on Maui (which had a peak demand of 197.7 MW-net in 2003) but it may not be large enough to defer new central station on Oahu (which had peak demand of 1,242 MW-net in 2003). Also, the larger sizes of DG that may be necessary to defer new central station capacity on Oahu may not even be considered DG on the smaller islands. As Mr. Scott Seu pointed out in HECO T-1, page 5, lines 12 and 13, "...a 5 MW unit might be considered DG on Oahu, but on Molokai and Lanai this size of a unit would be akin to a central station power plant and not DG."

CA-IR-25

Ref: HECO T-3, Page 11, Lines 17 through 19.

The testimony indicates that "[I]f a utility does a CHP system project instead of a third-party, the utility incurs costs (in the form of the CHP system investment and O&M expenses for the system), but retains revenues that would otherwise have been lost."

a. Can customer-owned or third-party owned DG be firm capacity if the DG unit provides control to the electric utility system? Explain.

b. If the third-party DG is metered and billed such that all of the customer's energy use continues to be billed at rates that reflect generation related costs and non-generation related costs, would the Companies' concern for the potential lost revenues be alleviated? Explain.

<u>HECO Response:</u>

a. It is not clear what is meant by "if the DG unit provides control to the electric utility system". As stated in HECO T-3, page 9, beginning line 13, "CHP...can be considered firm capacity where the utility is able to control the operations of and maintenance quality of the installation." As a practical matter, these conditions are unlikely to be met in the case of a specific third-party or customer-owned installation. The ability of third-party or customer-owned DG to reduce the load to be served by central station generation is discussed beginning on page 9, line 22, and continues on page 10 to line 12.

b. HECO does not understand the question. If a third-party installs, owns and operates a DG facility, meters and bills the customer for the energy use, and keeps the revenues, then HECO would have lost revenues. (Also, where the customer leaves the grid, there is no customer energy use that continues to be billed by the Company.)

CA-IR-26

Ref: HECO T-3, Engineering Standard Practice, Page 3, Rule Number 2.

The testimony indicates that there must be enough net generation running in economic dispatch so that the sum of the three-second quick load pickup power available from all running units, not including the most heavily loaded unit, plus the net loads of all other running units must equal or exceed 95 percent of the hourly system net load (which excludes power plant auxiliary loads but includes T&D losses). Please provide example calculations using real-life numbers that show how Rule Number 2 applies to the HECO systems.

HECO Response:

Regarding HECO-301, page 3, an example calculation of Rule 2 as it applies to the operation of the HECO system is provided below. This example is based upon the following snapshot of unit loads and corresponding quick load pickup ("QLPU") values available for each unit running on the system:

Quick Load Pickup Example:

Unit	Normal Top Load (MW)	Unit Load (MW)	QLPU Available (MW)
HECO Units			
H8	52.9	25.5	17.5
H9	54.4	27.1	19.7
W3	46.2	23.4	19.6
W4	46.4	24.0	19.0
W5	54.6	23.6	20.3
W6	55.6	31.1	16.1
W7	88.1	78.9	1.4
W8	88.1	62.7	10.6
W9	51.9	Not Running	Not Running
W10	49.9	Not Running	Not Running
K1	88.2	79.5	1.6
K2	86.3	77.2	2.9
K3	88.2	75.2	3.7
K4	89.2	83.9	0.4
K5	134.7	Not Running	Not Running
K6 *	133.9	124.9	1.9
IPP Units			
KPLP	180.0	189.9	** 0.0
AES	180.0	89.8	** 0.0
HPOWER	46.0	43.3	** 0.0
Total	**1,614.6**	**1,060.0**	**134.8**

* Most heavily loaded unit
** Does not provide QLPU

Note that all MW values provided in the table are system level net MWs and therefore are exclusive of power plant auxiliary loads but include T&D losses.

Rule 2 as written in the Engineering Standards Practice Manual can be expressed mathematically as:

QLPU (all units) – QLPU (most heavily loaded unit) + load (all units) – load (most heavily loaded unit) $\geq$ 0.95 x system load

Using values from the table above, the Rule 2 equation is:

$$134.8 - 1.9 + 1{,}060 - 124.9 \geq 0.95 * 1{,}060$$

$$1{,}068 \geq 1{,}007$$

Therefore, Rule 2 is satisfied.

CA-IR-27

Ref: HECO T-4, Page 8, Lines 14 through 19.

The testimony indicates that "non-T&D options such as implementing sustained demand side management ("DSM") programs and installing DG facilities have been considered in past T&D analyses and increased evaluation of non-T&D alternatives is being included in more recent T&D analyses." The testimony also indicates that "[n]on-T&D options related to DG facilities have included the evaluation of diesel generators at the Company's substations, customer-sited, utility-owned CHP programs and utilizing emergency standby generation."

a. Why have no other DG technologies other than diesel generators and CHP been considered?

b. Please provide copies of the analyses performed of DG facilities that have been considered by the HECO systems.

<u>HECO Response:</u>

a. Other DG technologies have been considered. For example, HECO T-4 in Docket No. 03-0417, page 67, describes how technologies such as wind, solar and fuel cells were considered in a study conducted by CH2M Hill in June 1995, entitled Kamoku-Pukele 138 kV Transmission Alternatives Study.

b. Studies and reports are listed in the attached tables. The studies and reports are voluminous and can be made available for review upon request. Please contact Dan Brown in HECO's Regulatory Affairs Division at 543-4795 to arrange for a review. See also the response to CA-SOP-IR-15.

TITLE	DATE OF PUBLICATION	DOCKET	UTILITY SYSTEM
Kamoku-Pukele 46 kV Alternatives Study	August 1994		HECO
Kamoku-Pukele 138 kV Transmission Line Alternatives Study	June 1995		HECO
HELCO North Kohala Diesel Engine Generators	December 1995		HELCO
HELCO North Kohala Transmission Study	December 1995		HELCO
East Oahu Transmission Requirements Update Study	March 1998		HECO
Hawaiian Electric Company, Inc. Review of the Distributed Generation Alternatives to the Kamoku-Pukele Line	March 2000		HECO
East Oahu Transmission Project: Options to the Koolau/Pukele Transmission Line Overload Problem	December 2003	03-0417	HECO
East Oahu Transmission Project: Alternatives Study Update	December 2003	03-0417	HECO
7200/7300 Line Overload Study Presentation	January 2004		HELCO

CA-IR-28

Ref: HECO T-4, Page 18, Lines 1 and 2.

This section of the testimony discusses the Companies' "Conceptual overview of T&D avoided cost calculation" and "Avoided costs." Please provide sample calculations with real-life numbers that illustrate a DG avoided cost analysis on the HECO systems. State all assumptions made in deriving the calculations and explain why these assumptions are believed to be reasonable.

HECO Response:

HECO does not have the requested information. Further, HECO objects to this information request on the grounds that providing "sample calculations with real life numbers that illustrate a DG avoided cost analysis on the HECO systems" is a labor intensive undertaking that requires specific information for an actual DG installation. In accordance with Prehearing Order No. 20922, at page 5, a party "...shall not be required, in a response to an information request, to make computations, compute ratios, reclassify, trend, calculate, or otherwise rework data contained in its files or records."

CA-IR-29

Ref: HECO T-5, Page 7, Lines 4 through 21.

The testimony indicates that "the cross subsidies embedded in the Companies' rates are one of the significant rate design and cost allocation issues that must be considered with the deployment of distributed generation in Hawaii" and that if the DG market develops significantly "the Companies' embedded cost of service study may be expanded to include DG customers as a separate class in the study."

a. Considering that the DG class could consist of residential and commercial customers, what subsidies, if any, do the Companies envision will be applicable to the DG class in the cost of service study? Explain.

b. What rate structure do the Companies envision will be applicable to the new DG rate class? Please explain how this rate structure was derived and provide copies of all calculations made to derive this rate structure, state all assumptions made and explain the basis for these assumptions.

c. Please expand on the "more detailed breakdown" of costs (described in lines 16 through 18 of the referenced testimony) that the Companies may include in the study and stated whether this expansion would occur absent DG deployment.

d. Please describe the "more detailed cost information" (referenced in lines 18 through 20 of the referenced testimony) that are presently not available or easily determined that would be required for the expanded cost of service study

e. What would be the "cost of developing and collecting the required data" described in lines 20 through 21 of the referenced testimony? Provide copies of all workpapers and/or calculations made to support the response, state all assumptions made in performing these calculations, and explain the basis for each assumption.

<u>HECO Response:</u>

a. The Companies do not have an estimate, at this time, of what subsidies, if any, will be applicable to the DG class in the cost of service study.

b. The Companies have not yet determined the rate structure appropriate for a potential new DG rate class. Depending on the nature of the CHP/DG market that evolves from the instant docket as well as the type of energy service that will be required by the DG/CHP customers, several rate structures such as time-of-use service, non-firm standby and/or maintenance service, and/or contractual standby/maintenance service, offer viable rate design alternatives for DG/CHP service.

c. The more detailed cost information that the Companies may include in the study, depending on the availability of data, may include such information as the customer's DG/CHP operating characteristics and availability (i.e., CHP/DG units' run time), the CHP/DG customer's load profile, the installed costs and operation and maintenance costs of utility-owned CHP/DG systems, and information on the CHP/DG's impact on the distribution and transmission costs. As stated in the referenced HECO testimony, the expansion of the Companies' cost-of-service study to include the CHP/DG customers as a separate class is dependent on the development of the DG market and the extent to which DG-related data is available.

d. See HECO response to part c. above. Data on the above information are not presently available or easily determined.

e. The Companies do not have an estimate of the cost of developing and collecting the required data as the nature and extent of the DG market that may evolve from the instant docket is still unknown.

CA-IR-30

Ref: HECO T-5, Page 10, Line 7 through Page 11 Line 7.

The testimony indicates that the "Companies' load-factor block energy rate form is a mechanism for minimizing intra-class subsidy, and is appropriate with the deployment of distribution generation as DG customers are served under these rate schedules."

a. Please explain how the load-factor block energy rate is a mechanism for minimizing intra-class subsidy, as opposed to a rate consisting of a non-load factor demand and energy rate structure with no demand-related costs included in the energy charges.

b. Why is the load-factor block energy rate form appropriate with the deployment of DG?

c. Other than the statement "DG customers are now served under these rate schedules", are there any other reasons why the Companies' load factor block energy rate form is appropriate with the deployment of DG? If so, please provide and explain such other reasons.

d. Are there any other appropriate rate structures for the deployment of DG? Explain why or why not.

HECO Response:

a. Both the "load-factor block energy rate" and a rate consisting of demand and energy charges that excludes demand related costs from the energy charges are mechanisms for minimizing intra-class subsidies. The cost recovery feature of the Companies' current load-factor block energy rate form is a mechanism for minimizing intra-class subsidy because most of the fixed demand and customer costs that are not recovered from the demand and customer charges are embedded in the energy rate for the first load factor block. This is important since the low load-factor customers may not be billed beyond the first load factor block. A rate consisting of demand and energy charges that excludes demand-related costs from the energy charges would eliminate intra-class subsidy between low load-factor and high load-factor customers. Such a rate design would be consistent with HECO T-5, page 15, that stated that more of the fixed costs should be recovered in the demand charges and/or customer charges, and thereby align rate elements closer to the cost components to provide more efficient pricing signals.

b. See HECO response to part a. above. Since DG customers will be served under the current applicable rate schedules, absent a separate rate schedule for DG customers, the cost recovery mechanism of the Companies' declining load factor block rate form is appropriate with the deployment of DG as these customers will more likely have low load factors.

c. See HECO response to part b. above.

d. See HECO response to CA-IR-29, subpart b.

CA-IR-31

Ref: HECO T-5, Page 11, Lines 9 through 20.

The testimony indicates that the Companies' rate design process takes into consideration, among other items, the fact that "3) rates must produce stable revenues and avoid rate shocks" and "5) rates must be fair, stable and equitable for all customers."

a. Will the Companies' current rate structures provide stable revenues and avoid rate shocks with the deployment of DG? Explain.

b. Are there circumstances where the deployment of DG under the Companies' current rate structure does not produce stable revenues and may cause rate shock? If yes, what are those circumstances and why would each produce this result?

c. Do the Companies' current rate structures provide fair, stable and equitable rates for all customers if the deployment of DG is to increase significantly? Explain.

<u>HECO Response:</u>

a. Presuming that the Companies are allowed to install CHP systems (in accordance with the CHP Program filed in Docket No. 03-0366) and implement their schedule CHP tariff filings, the Companies' ratepayers as a whole are better off with utility participation. As stated in HECO T-1, the Companies performed an extensive economic analysis in support of their CHP Program application considering all the numerous revenue and cost impacts, to show that the Companies' ratepayers as a whole are better off with utility participation.

If a third-party installed and owned the CHP system instead of the utility, the Company will lose revenue based on the reduction in demand and energy charges. The energy charge recovers a substantial percentage of the Company's fixed demand and customer costs, and the lost revenues far exceed any savings the Company will see in variable operating and maintenance costs associated with the customer's reduction in load and energy. Per the analysis that was done for the Companies' CHP Program application, a third-party CHP installation would ultimately have a negative impact on non-participating ratepayers.

If the Company installs a utility CHP system instead, it retains the demand and energy charge revenues from the sale of electricity (less the reduction, if any, in energy usage and demand due to the use of waste heat to displace electricity, and less the price reduction to reflect the benefits of customer-sited generation); it gains revenues from the sale of waste heat (therms) and from the facilities' charge for the absorption chiller (if an absorption chiller is included in the project); and it incurs the capital operating and maintenance costs for the CHP system installation.

The interests of all customers are taken into consideration primarily by structuring the program of installing utility-owned CHP systems so that non-participating customers are not burdened.

b. See the response to subpart a.

c. See the response to subpart a.

CA-IR-32

Ref: HECO T-5, Page 14, Line 18 through Page 15, Line 13.

The testimony indicates that the deployment of DG should include some rate realignments to reduce or eliminate the cross-subsidies, between and within rate classes.

a. Should such a realignment occur in the absence of the deployment of DG? Explain why or why not.

b. If so, what impact does the deployment of DG have on the a realignment of rates referred to on page 15, line 16 through page 16, line 6 of HECO-T-5?

c. Is unbundling of the Companies' rates reasonable for purposes of establishing rates and charges to recognize the different services provided to customers with the deployment of DG, even in absence of mandated utility industry restructuring in Hawaii? Explain.

d. It is indicated that the "information required to further unbundle the cost of ancillary services is not available." Please identify and describe the information required to further unbundle the cost of ancillary services that is not available.

HECO Response:

a. Yes. Realignment of rates and costs should occur even in the absence of the deployment of DG. Realigning rates and costs allows the Companies to more accurately recover its costs from the appropriate rate components and customers provides more efficient price signals to customers. Customers' future energy supply options may not be limited to the use of distributed generation. The lost fixed cost recovery impact of lost kWh sales resulting from customers' use of other energy supply options is minimized if rates are aligned with costs, which in turn will minimize adverse rate increase impacts on ratepayers. The cross subsidy of residential customer rates by commercial and industrial customer rates is also a consideration in the realignment of rates and costs. Aligning rates and costs will benefit both the Companies and the ratepayers in the long run.

b. HECO T-5, page 15, line 16 through page 16, line 6 relates to unbundling. Realignment of rates and costs becomes even more essential and imperative with the deployment of distributed generation as discussed in HECO T-5, page 13, beginning on line 19, through page 15, line 13.

c. Please see HECO T-5, page 15, beginning line 14, through page 16, line 6.

d. The information required include the identification of the ancillary services that are affected by the deployment of distributed generation. After the affected ancillary services are identified, the associated costs of such ancillary services or facilities or equipment such as the installed costs and operation and maintenance costs need to be identified. The load-related or customer-related or DG-related information required to develop the allocation factors need to be identified and collected. Also see HECO response to CA-IR-29, part c.

CA-IR-33

Ref: HECO T-5, Page19, Line 18 through Page 20, Line 11.

It is indicated that "[t]he energy rate discounts offered under the Rule 4 Rate Contract were set at amounts less than or equal to the percentage "subsidy" borne by the rate class." Next, it is concluded that "the rates (even with the discount) under the Rule 4 Rate Contract were still well above marginal costs."

a. Is the percentage "subsidy" borne by the rate class as referenced in the testimony the percentage as determined from the Companies embedded cost of service study?

b. If affirmative, how is it that staying within the embedded cost of service percentage subsidy results in rates "still well above marginal costs?"

c. Under the Companies' current rate structures, is the lost revenue from the deployment of DG retainable only through the application of standby charges, which as indicated may be voluntary for HELCO's system in the future, or through customer retention rate discounts provided under the Rule 4 Rate Contract? Explain.

<u>HECO Response:</u>

a. Yes, the percentage subsidy referenced is determined from the embedded cost of service study that is the basis of the Companies' current rates.

b. The statement is true for HELCO (Schedules J and P) where the embedded cost at full cost-of-service is greater than the marginal cost. The statement however is not true for HECO where the classes' embedded cost of service are lower than the marginal costs.

c. Lost revenue from the deployment of DG is lost to the Companies. There is no mechanism in the existing rate structures to recover revenue from lost kWh sales to DG customers. Standby charges recover the cost of providing standby service, not the shortfall in recovery of the fixed costs of regular service because of kWh sales lost to DG. The Rule 4 Standard Form Contract for Customer Retention rate was designed to retain loads for recovery of fixed cost-related revenues. The customer retention rate discount would not retain nor recover lost revenues resulting from customers installing DG.

CA-IR-34

Ref: HECO T-5, Page 20, Lines 17 through 21.

The testimony indicates that with "the evolution of the Companies' approach to DG/CHP, HECO and HELCO are in the process of reevaluating the applicability of the Rule 4 Rate Contract."

a. What are HECO and HELCO in the process of reevaluating?

b. How would this reevaluation by HECO and HELCO affect MECO?

HECO Response:

a. HECO and HELCO are assessing whether to maintain, modify, or eliminate their respective Rule 4 Standard Form Contract for Customer Retention rate.

b. The Companies' decision resulting from such assessment will apply to HECO, HELCO, and MECO. For example, if such assessment indicates that the Rule 4 Standard Form Contract for Customer Retention Customer rate is no longer applicable, the Companies will propose to eliminate such Rule 4 Standard Form Contract for Customer Retention rate for HECO and HELCO. MECO will not require any action since MECO does not have a Rule 4 Standard Form Contract for Customer Retention rate.

CA-IR-35

Ref: HECO T-6, Page 8, Line 2 through Page 9, Line 21.

a. With respect to customer-sited CHP systems, it is indicated that the "utility also provides backup and supplemental service to the customers." How do the Companies propose to charge such customers for the services provided?

b. Beginning at page 8, line 25 it is indicated that the other utility customers should "not be unduly burdened" by the utilities backup service provided to customers with customer sited CHP systems or DG. Does this mean that some level of "burden" could be reasonably applied to other customers? Explain.

<u>HECO Response:</u>

a. Under HECO's and MECO's <u>current</u> tariffs, the backup and supplemental service with respect to customer-sited CHP systems owned by the customer or third parties will be served under the current applicable standard rate schedule. Under HELCO's current tariffs, such service will be provided under the current applicable rate schedule and Rider A. Please refer to HECO T-5, pages 16-19, for a detailed discussion of standby service.

b. The Companies position regarding backup service is that fair and equitable rates should reasonably recover the costs of providing standby service from the customers imposing such costs.

CA-IR-36

Ref: HECO T-6, Page 11, Line 10 through Page 12, Line 1.

Do the Companies believe there are any other revisions that should be made to the Hawaii Public Utilities Commission's administrative rules and the Hawaii utility rules and practices to facilitate the successful deployment of DG other than the Companies' proposed CHP program and CHP tariff described in the referenced testimony?

HECO Response:

No, other than Commission approval of the Companies' CHP Program and Schedule CHP tariff, Docket No. 03-0366, and the expeditious review and approval of applications for individual CHP projects filed under the Companies' Rule 4 tariff, at this time the Companies do not believe that any revisions are necessary to State administrative rules and utility rules and practices to facilitate the successful deployment of DG in Hawaii.